Power Function Review II Managerial Workshop

March 8, 2006

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Reminder: Where We Have Been and Where We Are Going

- January-June 2005 PFR I
  - Reviewed Power costs for FY 2007-09
  - Found $96 M in cost reductions

- November 2005 Power Rate Case Initial Proposal
  - Used PFR I Power expenses
  - Updated forecast for hydro assumptions, market prices, loads, debt management items, DSI ROD, and other rate case items.

- January-April 2006 PFR II
  - Seek additional cost reductions to be included in the final power rate proposal

- Final Rate Proposal expected Summer 2006
  - Incorporate PFR II program expense levels plus update rate case assumptions (i.e., market prices, hydro assumptions, etc.)
  - Rates take effect October 1, 2006

Rate Case Initial Proposal

PFR II Purpose

To seek further cost reductions to make FY 07- 09 power rates as low as possible while still meeting mission objectives.

Opportunities to lower rates from three-year average PF Non-Slice expected value of $30.3/MWh* (posted rate is $30.6/MWh*):

1. **Risk Management**
   - Reduce need for PNRR through liquidity tools
     - If successful, this could lead to a possible $2/MWh decrease in the rate
2. **Increase Secondary Revenue Credits****
   - Improvements in FY 07- 09 Net Secondary Revenue
     - Rule of Thumb: Approximately $46 M = $1/MWh
3. **Cost Reductions**
   - Reductions that apply to Slice and Non-Slice Rate
     - Rule of Thumb: Approximately $59 M = $1/MWh
   - Reductions that apply only to Non-Slice Rate
     - Rule of Thumb: Approximately $46 M = $1/MWh
4. **Other Impacts**
   - Improvements in FY06 Modified Net Revenue
     - Rule of Thumb: Approximately $125 M = $1/MWh

*This rate includes the operating reserve credit included in the initial proposal

**This would likely have an impact on Risk and PNRR which may offset potential savings

Rate Case Update (Non-Cost Issues)

Line #	Issue	Update	Potential Rate Impact on FY 07-09 Rate	Average Yearly $ Amount
1	Liquidity Tools	▪Good progress on direct pay ▪Progress on Treasury Note ▪Some progress on customer pre-pay ▪Deferred work on pre-payment	-$2+/MWh	--
2	FY 2006 Secondary Revenues	So far so good. Update to be provided in April	Rule of Thumb: $125M = -$1/MWh	--
3	Reactive Credit	Change in proposed reactive credit	+$.2/MWh	$12M
4	Change in Operating Reserve Agreement	Rate case agreement	+$.2/MWh	$8M
5	Change in Fall Chinook Transport Study and RSW Schedule	Update to reflect change in schedule	+$.3/MWh	$15M

Rate Case Issue: Liquidity Tools

- **Why they are important:** Liquidity tools would provide BPA with temporary access to cash. They do not provide more cash, but change the timing of when BPA receives the cash. This may allow BPA to be less reliant on its own reserves to meet the TPP standard, thereby allowing lower rates.
  - **History:**
    - Pre 2002: Rate structure mostly relied on reserves to cover risk.
    - FY 2002 – 2006: Rate structure relied on variable rate mechanisms and PNRR to cover risk.
    - FY 2007 – 2009: Initial Proposal rate structure utilizes variable rate mechanisms and PNRR to cover risk. Liquidity tools would help lower this cost of risk.

- **The tools being pursued by BPA**:
  - Direct pay of Energy Northwest budget
  - Pre-payment of power bills by select customers, as needed
  - Delaying advanced payment of certain Treasury obligations from September to December with debt optimization proceeds
  - Line of credit with the U.S. Treasury

- **The current status of the situation:** Internal analysis is on-going for all of these tools. BPA staff are working with external parties as appropriate. For example, an IRS tax ruling has been requested on the direct pay option, and members of Congress have urged an expedited IRS ruling. Energy Northwest is supporting the effort. Staff are talking with Treasury about a line of credit. In addition staff are working with a group of customers to develop a pre-pay proposal to offer to interested customers.

Rate Case Issues: Revenue Impacts

Revenue Credit for Reactive Power

- Expected revenues used to set power rates reduced from $25 million per year in the initial proposal to $25 million in FY 07 and $12.5 million in FY 08-09. This reflects a proposed revenue range of $4 to $20 million for each year in FY 08–09.

- The bottom line is that power rates will slightly increase but we expect transmission and ancillary service rates to decrease resulting in lower delivered power costs to all regional ratepayers, all else being equal.

Revenue Credit for Operating Reserves

- BPA reached a resolution with rate case parties to remove from its initial power proposal the Operating Reserve Credit (ORC).

- The overall net impact is a lower revenue credit of approximately $10 million per year that was used to offset the power and slice rates in the initial proposal.

Rate Case Issues: F&W Hydro Operations Effects

- Since the Initial Proposal, events have taken place that result in a change in hydro operation assumptions for the FY07-09 rate period.

  Additional costs due to schedule revisions for surface passage improvements:
  2007 - $16.3M
  2008 - $ 2.0M
  2009 - $ 8.7M
  Total $27.0M

  Changes due to Fall Chinook Transport Study:
  2007 - $41.5M (additional cost)
  2008 - $ 7.1M (additional cost)
  2009 - $29.5M (savings)
  Total $19.1M (additional cost)

  Net effect of the two categories:
  2007 - $57.8M (additional cost)
  2008 - $ 9.1M (additional cost)
  2009 - $20.8M (savings)
  Total $46.1M (additional cost)

Rate Case Issues: F&W Hydro Operations Effects

Surface Passage Improvements

NONE	= no improvement
TEST	= improvement in place in test mode 50% of the time
FULL	= improvement fully implemented 100% of the time

	Initial Proposal Assumption			Final Proposal Assumption		
	2007	2008	2009	2007	2008	2009
LWG	FULL	FULL	FULL	FULL	FULL	FULL
LGS	NONE	TEST	TEST	NONE	NONE	TEST
LMN	TEST	TEST	FULL	TEST	TEST	FULL
IHR	FULL	FULL	FULL	FULL	FULL	FULL
MCN	NONE	TEST	TEST	NONE	NONE	TEST
JDA	NONE	NONE	NONE	NONE	NONE	NONE
TDA	TEST	TEST	FULL	NONE	TEST	TEST
BON	NONE	NONE	NONE	NONE	NONE	NONE

Note: These are planning dates and are subject to change based on regional input, research results, annual flow conditions, and funding availability.

Fall Chinook Transport Study

Initial Proposal Assumption			Final Proposal Assumption		
2007	2008	2009	2007	2008	2009
NO	YES	YES	YES	YES	?

Rate Case Issues: F&W Hydro Operations Effects

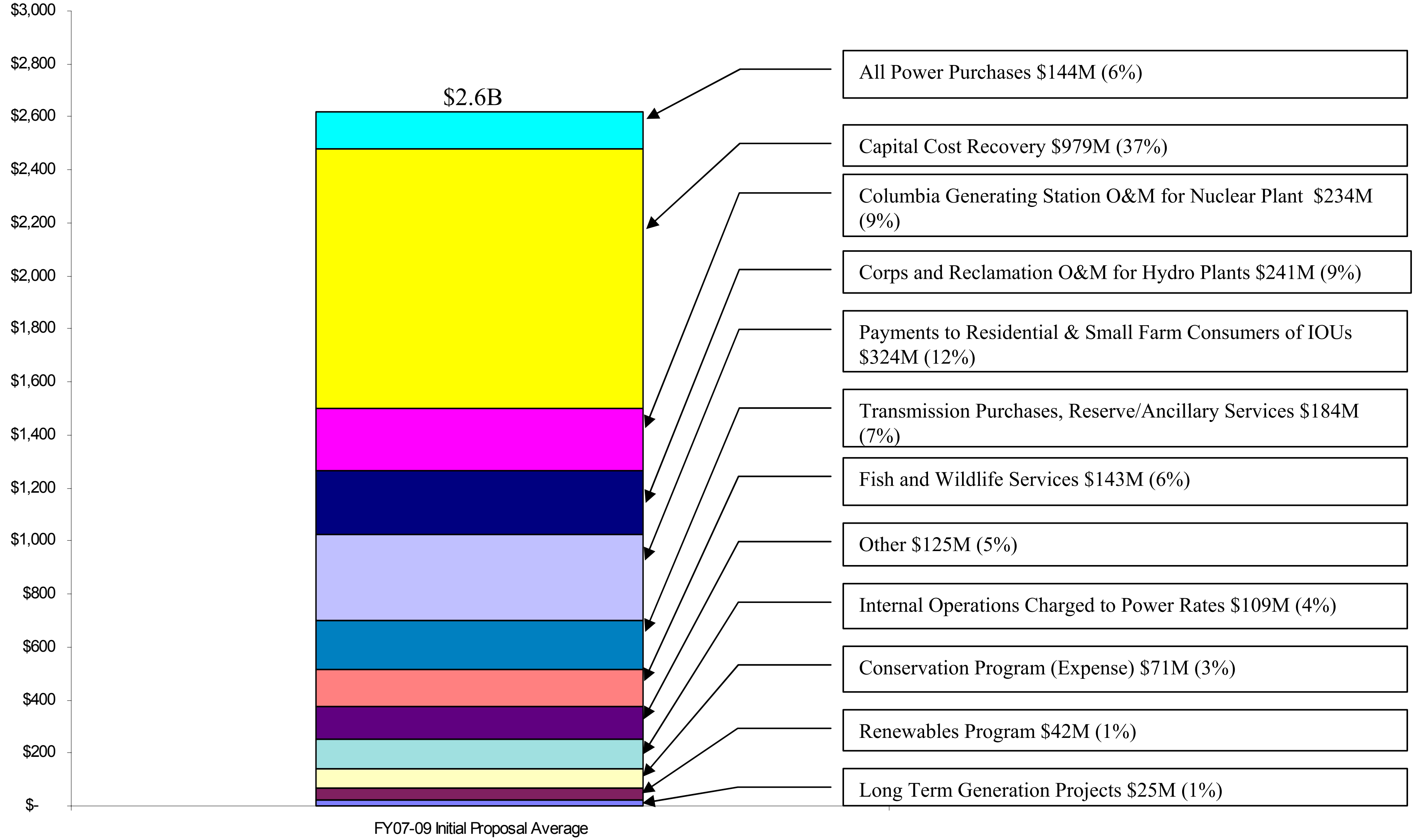
50-Year Average Generation Change from Initial Proposal to Final Proposal due to Surface Passage Improvements
(in aMW)

	April	May	June	July	August
2007	-88	-135	-119	-130	-97
2008	-29	-32	-30	0	0
2009	-69	-69	-69	-69	-69

50-Year Average Generation Change from Initial Proposal to Final Proposal due to Fall Chinook Transport Study
(in aMW)

	July		August	
2007	-545		-592	
2008	-72		-144	
2009	None 473	Yes -72	None 448	Yes -144

Average Annual Power Expenses for FY07-09



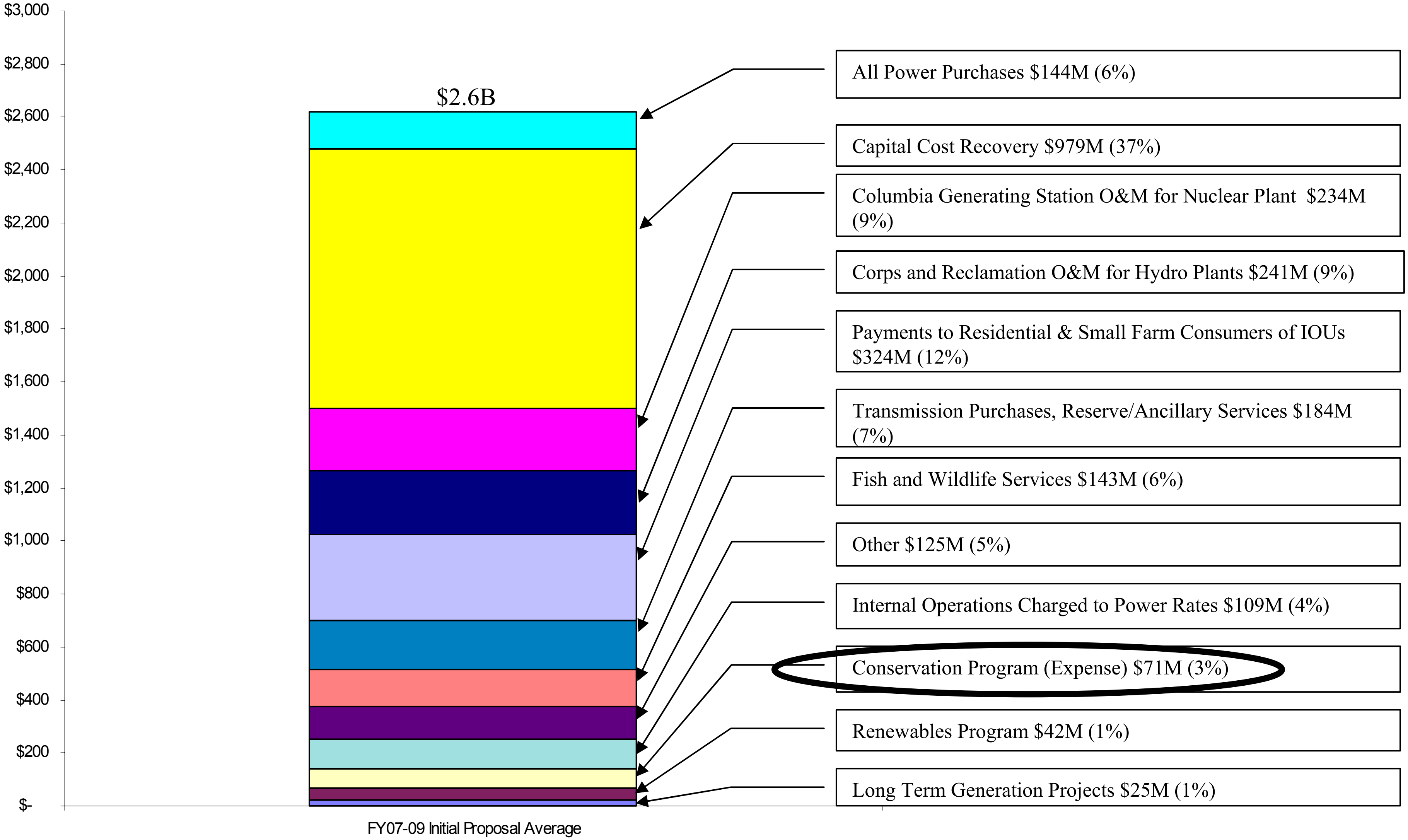
Scorecard as of March 8, 2006

	PFR II: Current Areas of Priority Focus	Likely		Under Discussion	
		+	-	+	-
1	**Capital Cost Recovery**				
2	Longer amortization period for conservation acquisition				$ 0.0
3	Longer amortization period for fish and wildlife investments				TBD
4	Use BPA borrowing authority for land and water acquisitions for fish				TBD
5	Extend existing CGS debt to 2024		$ (16.0)		
6	Longer maturity (to 2024) on debt for new CGS investments		$ (1.5)		
7	Update to reflect 2005 actuals in repayment studies		$ (3.5)		
8	Columbia River Fish Mitigation plant-in-service schedule -- DOD IG decision	$ 5.0			
9	Potential increases for CGS deferred maintenance (capital)	$ 2.5			
10	**CGS O&M**				
11	Potential increases for deferred maintenance (expense)	$ 14.0			
12	Consider not pursuing relicensing this rate period				$ (0.3)
13	**Corps & Reclamation O&M**				
14	Benchmarking federal projects O&M against other regional hydro projects			TBD	
15	**Residential Exchange**				
16	None				
17	**Transmission**				
18	Review transmission expense for secondary sales		$ 0.0		
21	**Fish and Wildlife**				
22	F&WL Monitoring and Evaluation (M&E)				$ 0.0
23	**"Other"**				
24	DSI $59 million annual support ($53M/yr is expected value in I.P. with risk)				$ (53.0)
25	Review Spokane settlement status			$ 6.7	
26	**Internal Operations**				
27	Examine potential for additional EPIP savings				TBD
28	**Conservation**				
29	Consider conservation done by utilities "on their own nickel"				TBD
30	Increase BPA funding for conservation			TBD	
31	**Renewables**				
32	Remove Calpine geothermal costs from 2009		$ (7.0)		
33	Consider increasing facilitation costs and backstop costs	$ 5.0			
34	**Long Term Generating Projects**				
35	None				
36	**TOTAL**	**$ 27**	**$ (28)**	**$ 7**	**$ (53)**

Power Function Review II

Conservation Program

Average Annual Power Expenses for FY07-09



Conservation Program

<u>Potential Cost Reduction (Scorecard, Line 29)</u>:

Reduce BPA's spending by crediting conservation done by public utilities "on their own nickel" against BPA's target.

BPA's goal:

To achieve BPA's share of the Council's Fifth Power Plan conservation targets at the least possible cost to BPA. Crediting cost-effective conservation done by utilities on their own nickel may be consistent with this goal.

What it would take:

- A tracking mechanism: Done. We have added a feature to the RTF Planning, Tracking and Reporting System for customers to report "self-funded" conservation.
- A determination of how much self-funded conservation occurs using tracking system data reported at the end of 2006.
- A method to give BPA and the region reasonable confidence that the reported savings are real and based on cost-effective measures as defined by the Council.
- Evaluate the information and make a decision about whether or not BPA should adjust its conservation targets and budgets for FY 2007 and beyond. This could be accomplished through impact evaluations of utility programs either funded by the utility or by BPA.

Criteria for eligibility:

Self-funded conservation credited to BPA would need to be incremental to the utility's own share of the Council's target.

Conservation Program

Issue:

- Historically, we have confidence in the conservation savings accomplished with BPA funds because we design with sufficient rigor in initial stages and we measure, oversee and evaluate to confirm the savings are realized. Assuming there turns out to be a significant amount of utility "self-funded" conservation, how should BPA evaluate these accomplishments in order to have the same level of confidence in the utility installed ECMs as in the "BPA-funded" conservation?

Feedback needed from participants:

- How do we "encourage" utilities to report their "self-funded" conservation (provide information on cost and savings for installed ECMs) in the enhanced RTF Planning, Tracking and Reporting System?

- How do we assure a consistent level of M&E for all the reported BPA and utility conservation savings?

Conservation Program

<u>Potential Cost Increase (Scorecard, Line 30):</u>

What are the impacts of increasing BPA's funding for conservation?

Status:

- For every 5 aMW of incremental conservation savings BPA is able to achieve, there would be a increase in rates of 0.08 mills/kWh ($1.3 M decrease in PF revenues, $2.5 M increase in surplus sales and a cost of $1.5M/aMW for delivering the conservation savings) in the 2007-09 rate period (assumes a market rate of $58/MWh and a PF rate of 30 mills/kWh).
- Currently, several generating customers are not meeting their share of the region's cost-effective conservation targets; many others express doubts about spending all their credits under the new CRC.

Feedback needed from participants:

- The Council sets the cost-effective conservation targets for the region and BPA is committed to achieving its share of that target. If BPA is proceeding at the pace the Council indicates is appropriate, should we increase production?

- Has BPA achieved a balance on funding and delivery now? Would additional funding, in the short term, help production or are there programs that need to be developed to deliver additional conservation savings in the future?

Conservation Program

Initial Proposal PBL Total Conservation Forecast FY 2007 - 2009

Program	Forecast	Annual MW Target Spending
Generation Conservation Expenses	$35.0M	
EE Development (Reimbursable)	$12.9M	
Energy Web/Non-Wires Solutions	$1.0M	
Technology Leadership	$1.3M	
Legacy (Contract closeout after FY 2000)	$2.8M	
Low-Income Weatherization	$5.0M	
Bi-Lateral Contract Activity	$1.0M	YES
Market Transformation	$10.0M	YES
Infrastructure Support and Evaluation	$1.0M	YES
Conservation Rate Credit	$36.0M	YES
Expense Total	$71.0M	
Generation Conservation Capital Total	$32.0M	
Utility & Fed Agency Bi-Lateral Contracts	$25.0M	YES
Third Party Bi-Lateral Contracts	$7.0M	YES

Initial Proposal Conservation Program Annual Targets and Budgets

Program	aMW	Budget	Cost/aMW
Rate Credit (at.5 mills = $42M*/yr with IOUs and pre-Subers included)+	20	$36M	$1.8M
Utility & Federal Agency Bi-Lateral Contracts+	17	$26M	$1.5M
Third Party Bi-Lateral Contracts	5	$7M	$1.4M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$1M	---
Total	52	$80M	$1.5M

*Assumes $6M/yr of the $42M/yr from a separate renewables budget will be spent on renewables.

+ Includes a 15% administrative cost allowance

Conservation Program

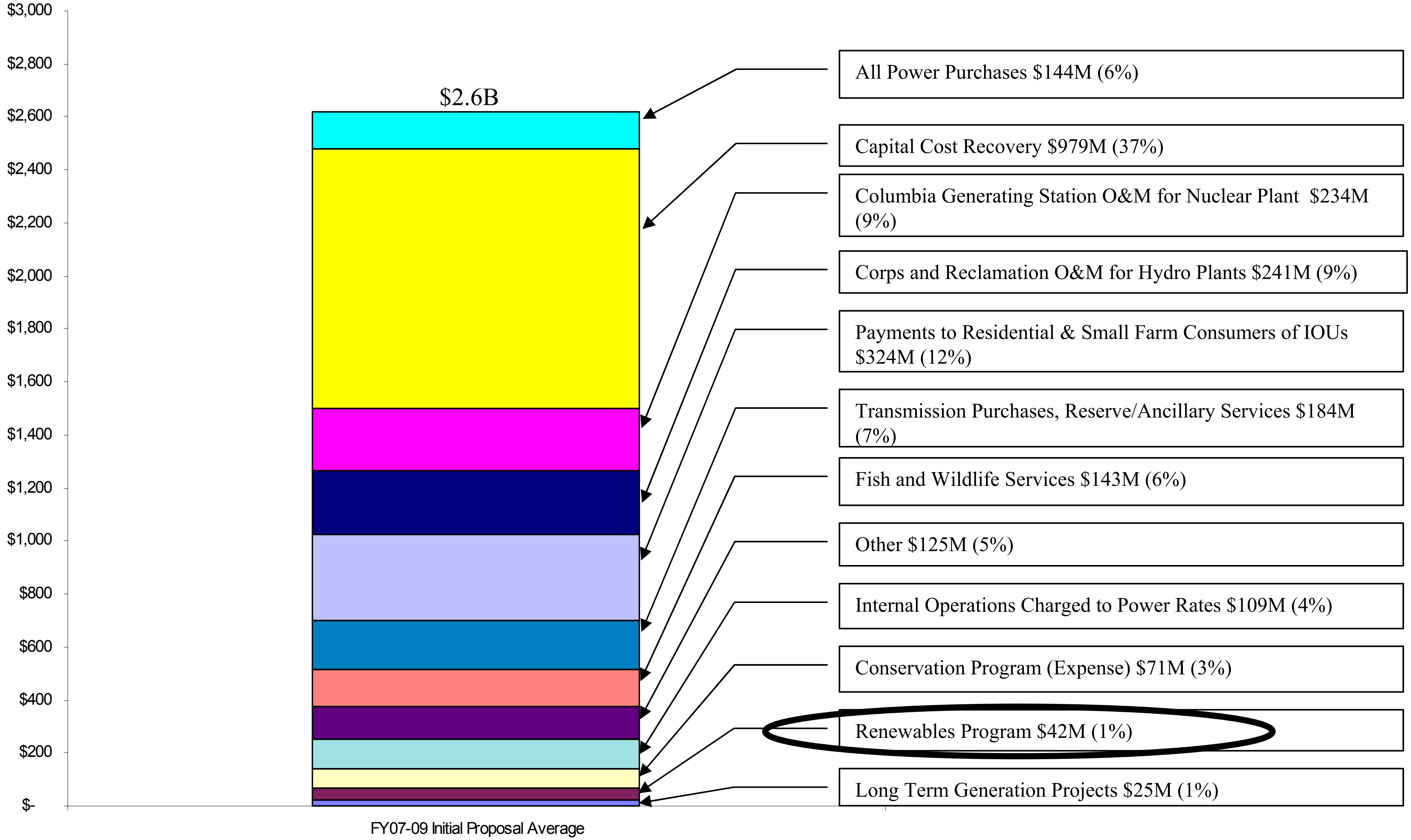
Maximum Discretion Reductions :

1. Eliminate Conservation Rate Credit (CRC) ($36M/yr)
2. Eliminate the 4-State Low Income Weatherization (LIWx) Program ($5M/yr)
3. Eliminate uncommitted Bilateral Conservation Contracts ($8M/yr)

Power Function Review II

Renewables Program

Average Annual Power Expenses for FY07-09



Renewables Program

Initial Proposal Renewables Program forecast included:

- $6 million/year for the Renewable Option to the Conservation Rate Credit (CRC).
- Green Energy Premiums dedicated to RD&D and non-energy producing renewable facilitation activities.
- Facilitation funds for FY07(up to $5.5 M) and FY08 (up to $11 M)

RENEWABLES PROGRAM COST FORECAST FY 2005-2009
Values Presented in BPA's Initial Rate Proposal

(UPDATED June 27, 2005)	FY 2005 ($)	FY 2006 ($)	FY 2007 ($)	FY 2008 ($)	FY 2009 ($)	
RENEWABLES PURCHASE COSTS						
Wind	***$ 18,022,285***	***$ 18,328,728***	***$ 18,650,143***	***$ 19,061,528***	***$ 20,161,695***	
Fourmile Hill	*-*	*-*	*-*	*-*	*31,678,389*	1/
Total Purchase Costs of Power Projects	**$ 18,022,285**	**$ 18,328,728**	**$ 18,650,143**	**$ 19,061,528**	**$ 51,840,084**	
SUPPORT AND OTHER COSTS						
Solar Data Collection - UO	*101,748*	*104,800*	*107,944*	*111,182*	*114,518*	
Wind Data Collection - OSU	*70,226*	*72,483*	*74,657*	*76,897*	*79,204*	
Wind Forecasting Study	*100,000*	*100,000*				
EPP/ REC Mkting Support	*20,000*	*20,000*				
Wind Data - Maint. Contract	*45,000*	*45,000*				
Project Development Costs	*163,026*	*157,717*	*332,399*	*342,370*	*352,642*	
PLUS:						
BEF MOA	136,000	136,000	388,562	389,489	766,238	
Wind Project Termination	250,000	-	-	-	-	
Facilitation Costs	-	-	5,500,000	11,000,000		2/
Total Support and Other Costs	**$ 886,000**	**$ 636,000**	**$ 6,403,562**	**$ 11,919,939**	**$ 1,312,602**	
Corporate Charges - KEC	*132,941*	*17,614*	*18,561*	*19,387*	*20,256*	
Corporate Charges - Gen. Counsel	*27,169*	*24,487*	*25,344*	*26,231*	*27,149*	
Total Corporate Charges	**$ 160,110**	**$ 42,101**	**$ 43,905**	**$ 45,618**	**$ 47,405**	
PLUS: Renewable Rate Incentive	**$ -**	**$ -**	**$ 6,000,000**	**$ 6,000,000**	**$ 6,000,000**	
TOTAL COST OF RENEWABLES PROGRAM	**$ 19,068,395**	**$ 19,006,829**	**$ 31,097,610**	**$ 37,027,085**	**$ 59,200,091**	

1/ BPA is proposing to zero this budget item by moving Fourmile Hill to FY 2010.
2/ A $16 million facilitation budget will be added for FY 2009 ($11 million plus $5 million for C&RD makeup).

Renewables Program

PFR II proposed changes to Initial Proposal forecast

<u>Potential Cost Reductions (Scorecard, Line 32):</u>

– BPA is proposing to move the Fourmile Hill Geothermal Project out of the 2009 budget and into FY 2010 which would result in a savings of approximately $21M for FY09 or $7M/year on average over the rate period.

<u>Potential Cost Increases (Scorecard, Line 33):</u>

– In lieu of the Fourmile Hill, BPA is proposing to include $11 million in the FY 2009 budget to facilitate the region meeting the Council's forecasted wind generation which results in an increase in costs of about $4M/year on average over the FY07-09 rate period.

– In addition, BPA is proposing to make good on it's commitment (February 2001 ROD on the C&RD Implementation Manual) to back-stop customer renewable spending under the current C&RD program.

– As a result of this commitment, BPA is proposing to include an additional $5 million in the FY 2009 facilitation budget, bringing the FY 2009 renewable facilitation budget to $16 million ($5M/year on average).

Renewables Program

How BPA proposes to spend the FY07-09 Facilitation Funds

- BPA's Renewable Target based on the Council's 5th Power Plan

- Council's 5th Power Plan calls for 5000 MW of new wind, region-wide over the next 20 years. BPA's share of regional load can be assumed to equal to 40%. Arguably, BPA's share of the Council's regional renewable futures could be 40%, or up to 100 MW/year.

- However, the Council's Plan predicts fewer resources in the near-term and more later. There fore BPA is proposing to facilitate up to 50 MW of <u>new</u> renewables investments per year over FY's 2007-2009

- Over time, BPA will revise our MW target as the Council revises their generation assumptions.

- BPA is proposing to accomplish this MW target at the least cost, spending up to the combined total of our "Renewable Program Support", "Facilitation Cost" and "Renewable Rate Incentive" budgets. (See slide 7 for budget line items.)

- BPA is proposing to dedicate the Facilitation budget to public customer renewables. To be clear, the proposed 2007-2009 Facilitation budgets are as follows:
  - FY 2007 up to $5.5 million.
  - FY 2008 up to $11 million.
  - FY 2009 up to $16 million. (This is new)

Renewables Program

Transition to Long-Term Regional Dialogue

– If BPA offers a Renewable Tier II product, it is conceivable that Tier II need could be established and demonstrated as early as FY 2009 via contract mechanisms. BPA may choose to use FY07-09 facilitation funds to cover the pre-development costs associated with Tier II renewable resources.

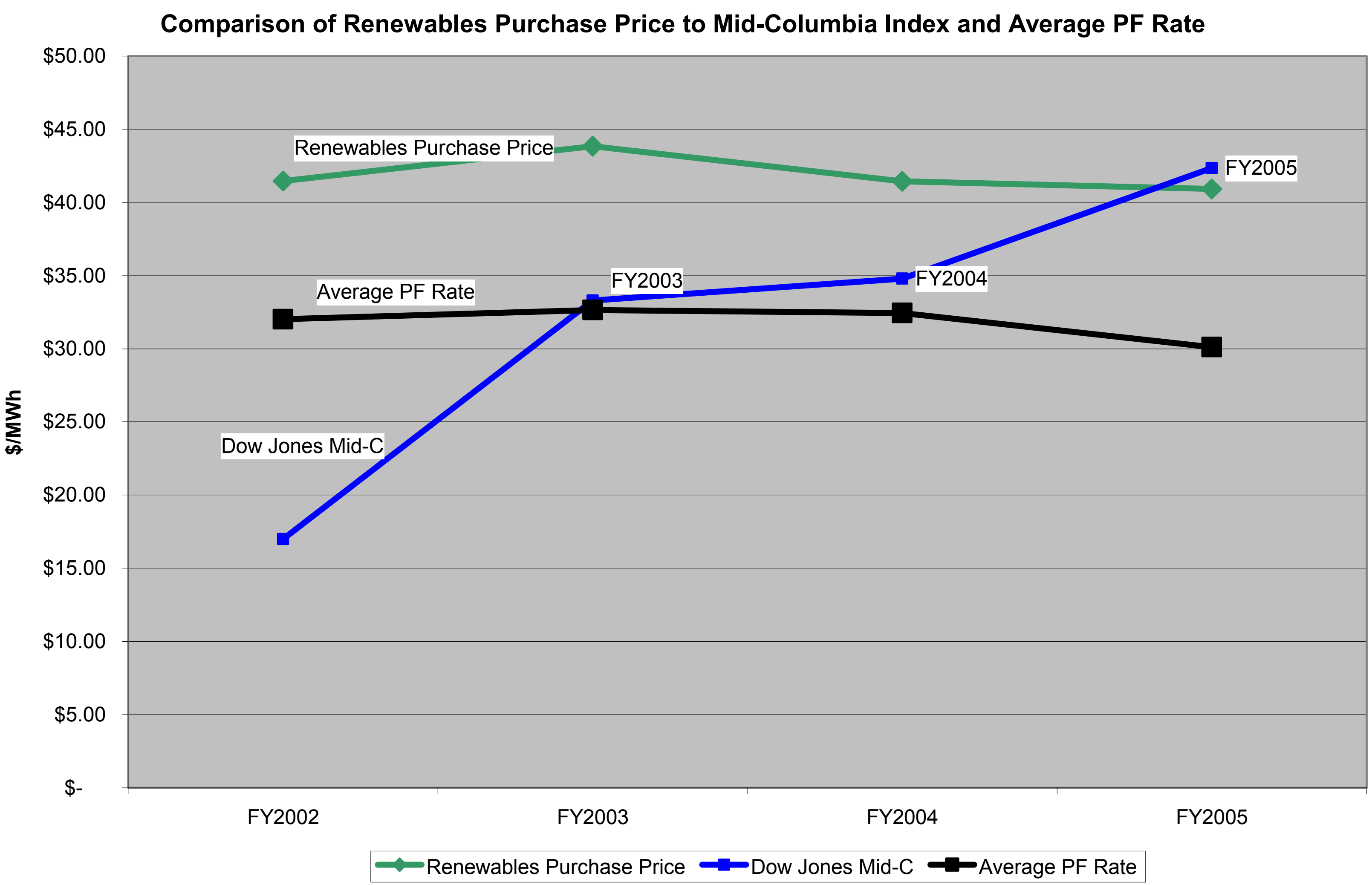
– BPA may choose to meet resource needs during FY 2007- 2009 with cost-effective renewables. We may also choose to meet Tier II renewable needs as early as FY 2008 or FY 2009. However, BPA is not proposing to acquire resources in absence of need simply to meet the MW targets.

Renewables Program

Maximum Discretion Reductions:

1. Eliminate Uncommitted Initial Proposal Facilitation Costs ($6M/yr)
2. Eliminate Renewable Rate Credit ($6M/yr)

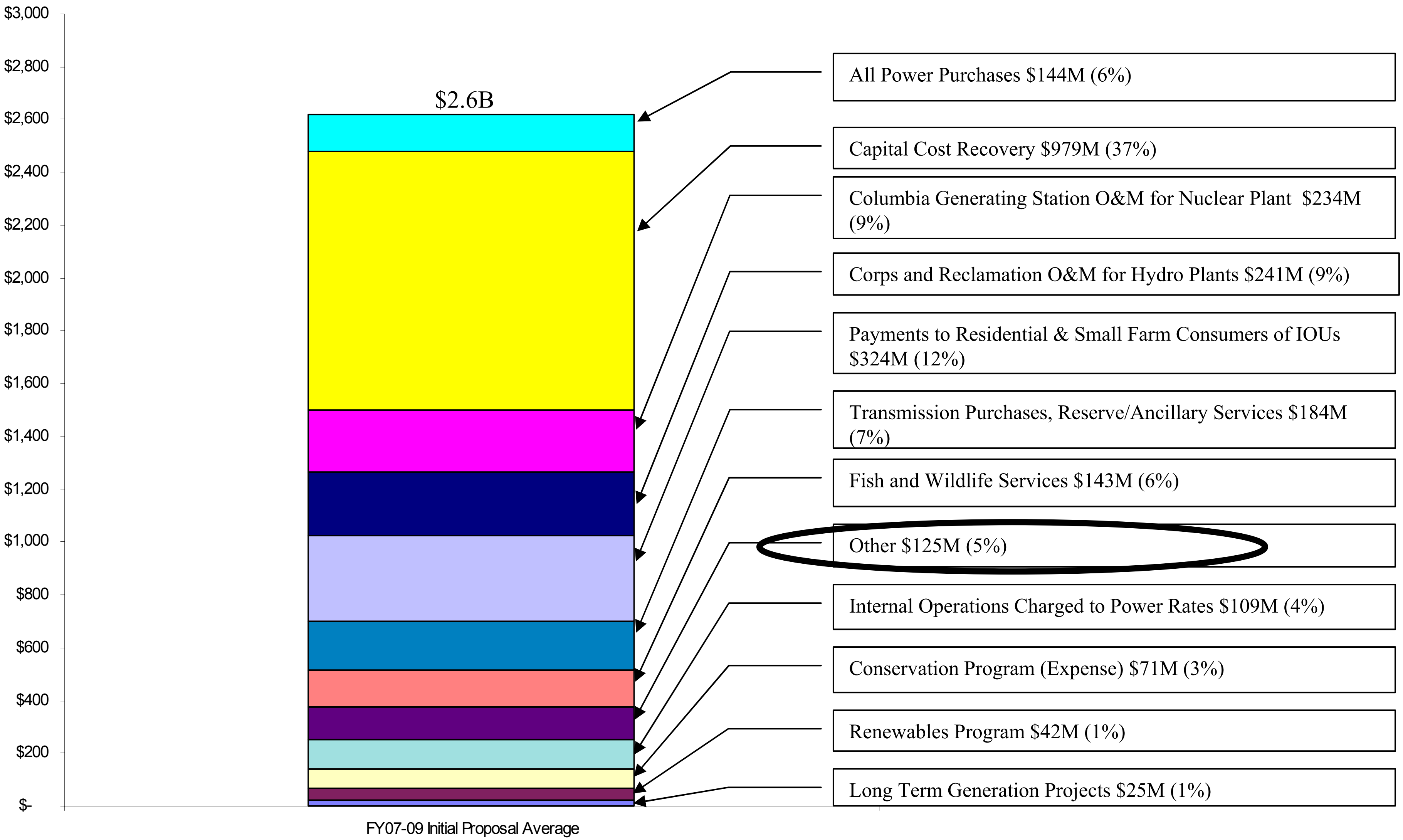
Renewables Program



Power Function Review II

DSI Benefits

Average Annual Power Expenses for FY07-09



DSI Benefits FY2007-2009 – Benefit Level?

Potential Cost Reduction (Scorecard, Line 24):

- Based on comments received during the review of the DSI prototype contracts BPA decided to review smelter service costs in PFR II.
- BPA had intended to sign contacts in mid-February but now plans to sign contracts at the end of April concurrent with the completion of PFR II.
- DSI benefit level decisions may be made sooner than the end of April if smelter management needs to implement business decisions that might be informed by BPA's decision. Power prices have generally been too high for DSIs to consider operating but are prices are dropping.
- $59 million/year was included in the Initial Proposal as a cap on the cost of providing aluminum smelters service benefits.

DSI Benefits FY2007-2009 – Benefit Level?

- **Reasons Why Proposed Benefit Amount May be Less than the $59 Million in the Initial Proposal:**
  - There is some question about the ability of GNA to restart and get financial benefits since their smelters are shutdown and coming out of bankruptcy.
  - Aluminum smelters will not operate under all power market conditions. With very high power prices it is likely some smelters will shut down.
  - With low market prices maximum yearly benefits will be reduced below the $59 million cap since DSIs cannot receive better value than PF
  - When acquiring unused benefits an aluminum smelter may not increase its allocation above the power amount specified in its current Subscription Contract.
  - Financial benefits unused for 18 months disappear permanently and are no longer available for any aluminum smelter.

DSI Benefits FY2007-2009 – Benefit Level?

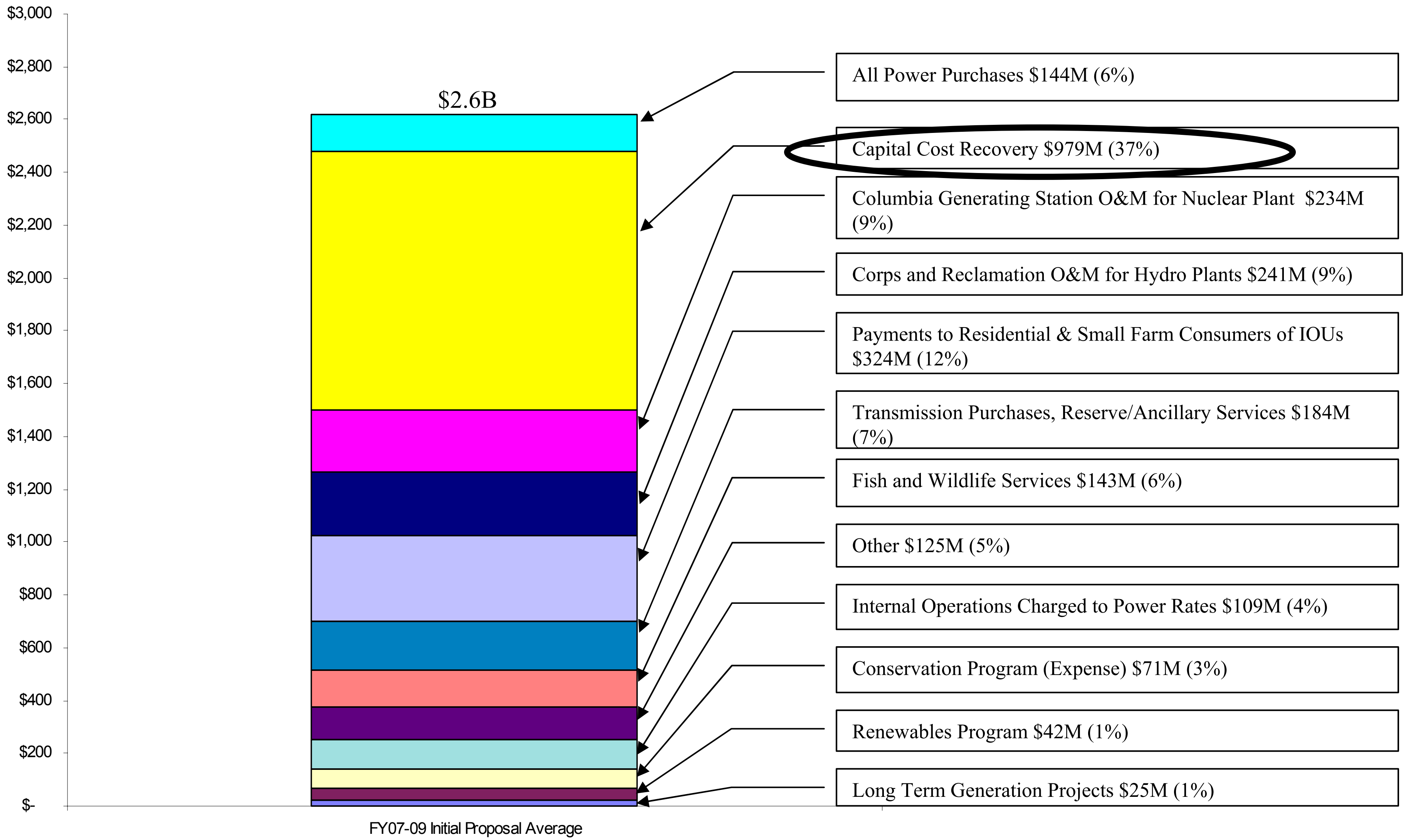
The benefit level was never intended to enable aluminum smelting under all market conditions but is an attempt to strike the right balance between supporting aluminum jobs and the cost incurred by BPA's other customers.

Options for Final Proposal

Power Function Review II

Capital Cost Recovery

Average Annual Power Expenses for FY07-09



Revenue Requirement Analysis

Potential Cost Reductions (Scorecard, Lines 5-7):

- BPA has updated repayment studies to reflect several changes. While these studies are not the Rate Case Final Proposal studies, they are likely closer than the Rate Case Initial Proposal to what will be in the Final Proposal. This analysis will change when other assumptions or variables are updated.
- The following tables illustrate the sum of the capital-related components of the revenue requirement – non-Federal debt service, net Federal interest, depreciation, and minimum required net revenues.
- The Rate Case **Initial Proposal** repayment study was used as the basis for the analysis.

Capital-Related Components of Rate Case Initial Proposal (adjusted for Initial Proposal offsets in Toolkit):

($ in thousands)	**2007**	**2008**	**2009**	**Average**
Initial Proposal	980,887	1,012,754	1,010,458	1,001,366

Analysis continued

Updated Base: To provide up-to-date analysis for planning purposes, a new base repayment study was run. This entailed:

- updating 2005 borrowing, repayment, and plant-in-service with actual FY 2005 actions ($3.5M/year);
- making technical corrections to EN debt service;
- assuming that capital additions for CGS would be financed through 2024 instead of 2018 ($1.5M/year);
- $350 million of EN debt will be refinanced and extended out through 2024 ($16 M/year);
- no change to Initial Proposal projected Federal or non federal borrowing capital investment forecasts.

Capital-Related Components of Updated Base (before risk):

($ in thousands)	**2007**	**2008**	**2009**	**Average**
Updated Base	965,186	983,567	993,747	980,834
Change from IP	(15,701)	(29,187)	(16,711)	(20,533)

- The major components of change when compared to the Initial Proposal include:
  - Non-Federal debt service decreases by an average of $44 million per year.
  - Net Federal interest decreases by an average of $7 million per year.
  - Minimum required net revenues increases by $12 million per year because of higher Federal amortization payments.
  - Adjustment for Toolkit offset which decreases the IP by an average of $19 million per year.
- Note that the Rate Case Final Proposal will likely include other changes such as updated capital forecasts, interest rate forecast, CRFM plant-in-service schedules, and EN debt service.

Amortization Period of Conservation Acquisition Investments

Evolution of the Policy

Potential Cost Reduction (Scorecard, Line 2):

- The conservation augmentation declining ten-year amortization period will not be applied to investments made after 2006.
  - The declining ten-year period was used to correspond of the period for which the benefit was to be derived – power augmentation during the 2002-2006 rate period.
  - The conservation program is shifting from augmentation to acquisition, eliminating the reliance on the 2011 contract period for cost recovery.
- New conservation acquisition investments are expected to be amortized using a five year, straight-line method.
- Reasons for selecting five years include:
  - The new policy will limit the growth of SFAS 71 assets over time, reducing growth of regulatory assets, which decreases the risk of stranded investments. It is also viewed more favorably by rating agencies.
  - When compared to longer amortization periods, a five year period results in the least pressure on borrowing authority. With a five-year repayment, the use of borrowing authority will peak and sustain at $160 million. A fifteen-year period could produce a peak of $480 million before principal repayment matches new investments.
  - Utility industry practice is mixed. Most appear to expense conservation investments in the year incurred. Some use a five or ten-year period. Very few use a period longer than ten years. A five-year period appears to be more consistent with industry practice.
- The potential amortization period is not unlimited
  - Accounting standards provide criteria for establishing amortization periods that begin with determining the useful life.
  - The composite life of conservation measures planned to be installed after FY 2006 as identified by the Council is fifteen years, which establishes the maximum amortization period.

Effect of a Longer Period

- To estimate the effect of changing the amortization period for conservation investments, we changed the conservation assumption in the **Updated Base** repayment study from 5 years to 15 years. All other assumptions were held constant.
- Changing the conservation assumption to 15 years produced almost no change in the revenue requirement. The net effect was a reduction of less than <u>$250,000 per year</u>. The effect in later years is more pronounced through 2015 and declines sharply afterward.

Estimated Revenue Requirement Impact

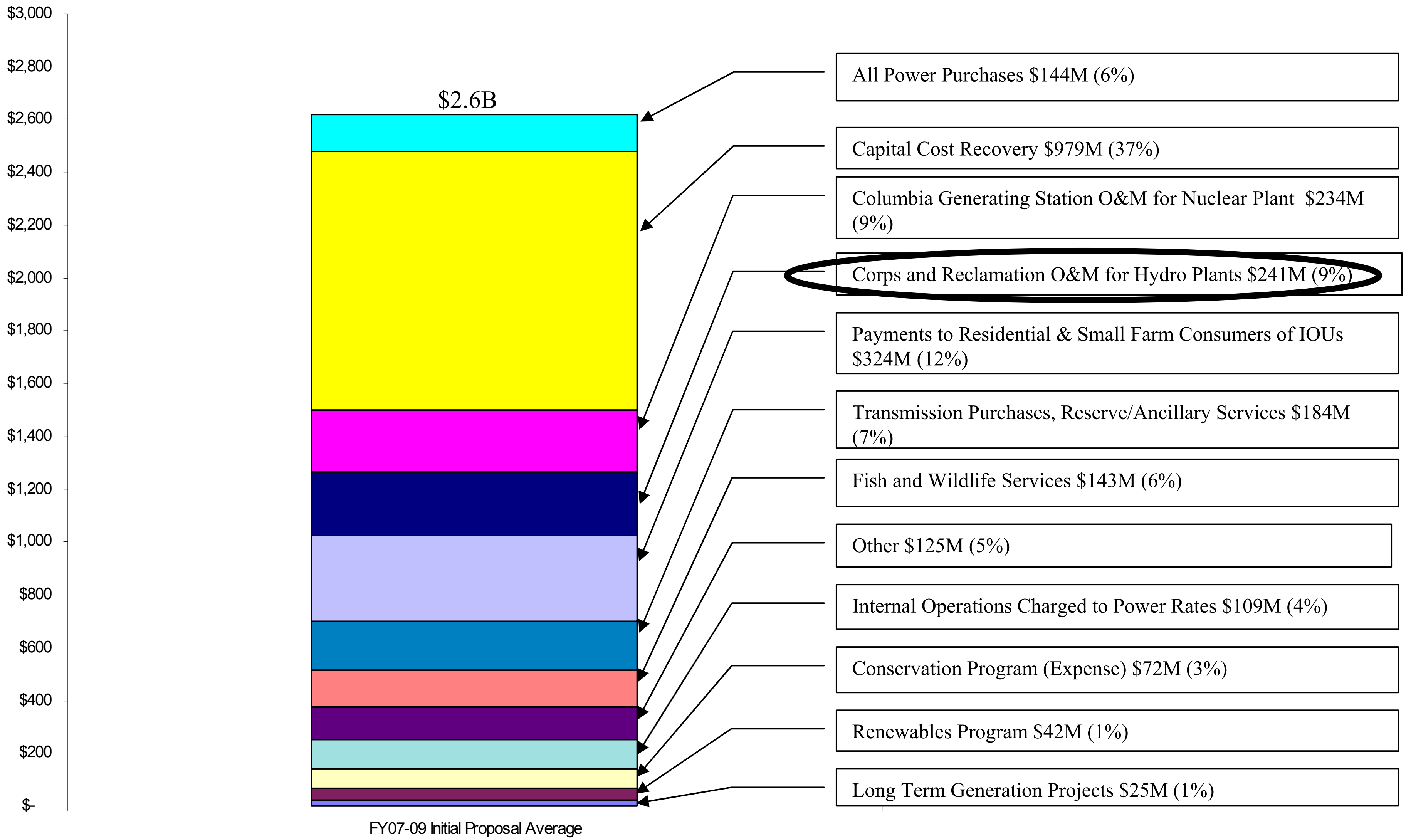
($ in thousands)	**2007**	**2008**	**2009**	**2007-2009 Annual Average**	**2010-2011 Annual Average**	**2012 - 2015 Annual Average**
15 year conservation	965,064	983,280	993,413	980,586	1,013,024	1,078,699
Change from Updated Base	(122)	(287)	(335)	(248)	(1,648)	(25,435)

- The major components of change in FY 2007-2009 when compared to the Updated Base include:
  - Depreciation decreases by an average of $6.4 million per year.
  - Net Federal interest increases by an average of $.4 million per year.
  - Minimum required net revenues increases by $5.7 million per year because of lower depreciation ($6.4 million/yr) and lower Federal amortization ($.7 million/yr).

Power Function Review II

Corps and Reclamation O&M

Average Annual Power Expenses for FY07-09



Columbia River Fish Mitigation Plant-in-Service Update

Columbia River Fish Mitigation Project

US Army Corps of Engineers

- **Purpose**: Mitigate impacts to anadromous fish passage at the Columbia/Snake River run-of- river dams
- **Authority**: Original Congressional dam construction and operation authorities
- **Project initiation**: 1991
- **Funding source**: Congressional appropriations
- **Estimated project cost**: $1.5 - $1.6 Billion
- **Estimated completion date**: 2014

- **Primary focus - passage facility configuration and operations at the dams**
  - Evaluate project and system fish passage & survival
  - Identify/develop/construct passage improvements
  - Seek cost effective alternatives
  - Implement Biological Opinions
  - Regional coordination
    - Biological/technical review &input
    - Advise on priorities

- **Repayment**

  - BPA accepts responsibility to repay “power share” of costs
  - Transfers to Plant-in-Service
    - Costs transferred when a new facility goes into operation
    - Prior Congressional guidance for “mitigation analysis” costs within the project
      - Hold until mitigation analysis “completed”
    - *Tentative* new guidance for “mitigation analysis”
      - Transfer backlog of completed studies
      - Transfer current/future studies upon completion

Effect on PBL Expenses

Potential Cost Increase (Scorecard, Line 8):

- Including the current estimate of the plant-in-service schedule will change of the revenue requirement. BPA does not have repayment study analysis of this change.
- The table below shows only the estimated depreciation and interest expense changes associated with the revised schedule. It is shown in comparison to the information presented during the Power Function Review last Spring.
- The effect on the revenue requirement will depend on how this change interacts with other new assumptions that will be used in the final proposal repayment study.
- Note that the expense effects are delayed by one year because plant goes into service at the end of the fiscal year. So, moving plant into service in 2006 will result in increased interest and depreciation expenses in 2007, not in 2006.

Estimated Interest and Depreciation Expense Changes ($ in millions)

	2006	2007	2008	2009
PFR Plant-in-Service Schedule	**$ 22**	**$ 76**	**$ 136**	**$ 6**
Interest Expense	$ 28	$ 31	$ 36	$ 40
Depreciation Expense	7	8	9	10
Cumulative Total	$ 35	$ 39	$ 45	$ 50

	2006	2007	2008	2009
Revised Plant-in-Service Estimate	**$ 284**	**$ 91**	**$ 86**	**$ 62**
Interest Expense	$ 23	$ 37	$ 41	$ 45
Depreciation Expense	6	10	11	12
Cumulative Total	$ 29	$ 47	$ 52	$ 57

Hydro Benchmarking

Corps & Reclamation O&M
NW Regional Benchmarking: Preliminary Findings

Potential Cost Reduction (Scorecard, Line 14):

- General
  - Similar wage rates at NW hydro stations.
  - Similar staffing levels within peer groups.

- Operations (11 percent of benchmarked expenses)
  - All NW Large stations have similar cost per unit and are at the HJA Consulting North American panel average cost.
  - For FCRPS stations with staffed control rooms the cost per unit is higher than other regional stations that have been automated. This difference is larger with smaller stations.

- Plant Maintenance (13 percent of benchmarked expenses)
  - NW stations generally have lower maintenance costs than the North American panel.
  - Tacoma was identified as a leading performer for maintenance at Medium and Small stations. Tacoma attributes this success to two factors: 1) small workforces with a great deal of knowledge of and ownership in the facility, and; 2) continuous improvement of work processes for managing the maintenance program.

- Support (18 percent of benchmarked expenses)
  - 70 percent of NW stations are in the Lower-Mid to Lowest cost quartile of the North American panel.
  - The analysis suggests that supporting multiple functions (i.e., power, navigation, recreation, etc.) results in lower support cost per function than when serving a single function.

- Waterways and Dams / Buildings and Grounds Maintenance (8 percent of benchmarked expenses)
  - NW stations have low cost relative to the North American panel.
  - Generally, FCRPS stations have low cost within the region.

- Public Affairs and Regulatory (50 percent of benchmarked expenses)
  - 70 percent of NW stations are in the High to Upper-Mid quartiles of the North American panel.
  - Boundary and Skagit have the lowest PA&R costs within the region.

Corps & Reclamation O&M

Maximum Discretion Reductions:

1. Eliminate Non Routine Extraordinary Maintenance ($8M/yr)
2. Reduce Capital Investment into FCRPS by the remaining amount of uncontracted or uncommitted budget ($7M/yr)

Power Function Review II

CGS O&M

Estimated Change to FY07-09 Revenue Requirement for CGS

Potential Cost Increase:

Operating Costs BPA FYs - Dollars in Millions

	Average 2007-2009
Initial Proposal Revenue Requirement	234.0
Latest Revised Estimate	247.8

•The current rates and the Initial Proposal for FYs 2007 through 2009 assume that CGS capital will be debt financed. The estimates above reflect this assumption.
•NEIL insurance and CGS Decommissioning Trust Fund contributions are included in the estimates.
•The Latest Revised Estimate (LRE) is a draft. Energy Northwest and BPA are continuing to review the forecasts. Changes in the estimates are expected prior to the Final Rate Proposal.

Estimated Change to FY07-09 Revenue Requirement for CGS

Potential Cost Increase (Scorecard, Line 9):

BPA FYs - Dollars in Millions Total Capital

	Average 2007-2009
Initial Proposal Revenue Requirement	20.0
Latest Revised Estimate	42.9

Debt Service on Capital

	Average 2007-2009
Initial Proposal Revenue Requirement	5.9
Latest Revised Estimate	8.4

- The estimates provided in this table will change prior to the Final Rate Proposal as the capital amounts get finalized and the Repayment Model is run.
- The estimates assume that 100% of capital will be debt financed.
- We are considering expensing the taxable portion (5% of capital) of the FY 06 financing due to the negative impacts it would have on the entire 2006 financing/refinancings.

CGS License Extension

Potential Cost Reduction (Scorecard, Line 12):

BPA Fiscal Years
Dollars in Millions

	Average 2007-2009
Initial Proposal Revenue Requirement	2.8
Latest Revised Estimate	2.5

- Estimated Total Project Costs approximate $15M
- The project will begin in Energy Northwest FY 2007 and continue through FY 2012.
- The estimate above is a draft and may change prior to the Final Rate Proposal.

Rate Case Issues: CGS Generation Forecasts

PNCA Operating Years – Gigawatt Hours

	2002	2003 Outage Year	2004	2005 Outage Year	2006	2007 Outage Year	2008	2009 Outage Year
Actual Generation	9,025	7,589	9,608	7,597				
PNCA Target - Rate Case input	8,760	7,680	8,784	7,680	8,760	7,680	8,760	7,680
(Under)/Over Target	265	(91)	824	(83)				
Energy Northwest Budgeted Generation	9,478	8,574	9,627	8,266	9,556	8,452	9,582	8,717

- In operating year 2004, CGS set a generation record.
- 1,000 aMW (877 aMW outage year) is a conservative estimate that has been reasonably accurate in previous years.
- CGS has completed its second two year refueling cycle. Additional experience with the two year refueling cycle is needed to support increased generation forecasts.
- Future outage lengths are uncertain at this time as Energy Northwest is reviewing projected maintenance and project plans, and implementation schedules.

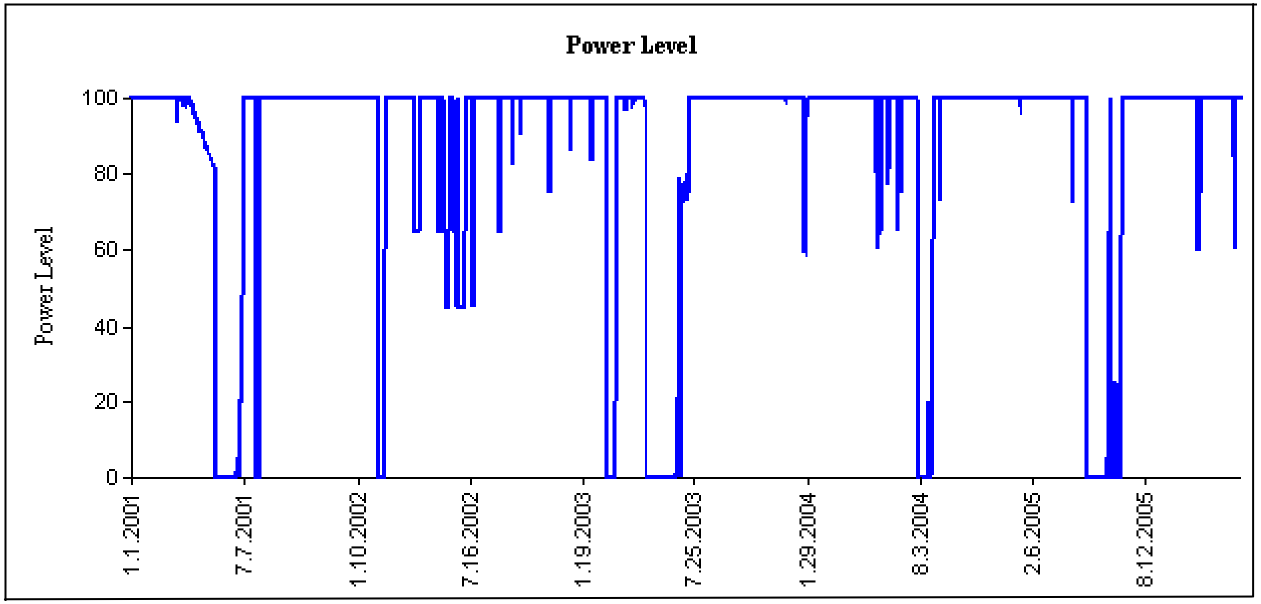
Uranium Tails Pilot Project (UTPP) Status Update

- The UTPP is a pilot project for recycling 8,500 metric tons of DOE depleted uranium tails for end use in the fuel cycle at Columbia Generating Station (CGS).
- The PFR's recommendation last year was for BPA and Energy Northwest to continue to pursue this project.
- DOE, EN and BPA reached an agreement, and the UTPP commenced on May 31, 2005.
- The project is approximately 50% complete, on budget and expected to be completed by the fall of 2006.
- The UTPP will produce enough uranium for 4 reloads (8 years) of operation at CGS starting with the 2009 reload.
- The current estimated project cost is at approximately $94 million and is being financed with EN general fuel procurement bonds. This cost was included in the Initial Proposal forecast.
- Based on the current spot market price for uranium, the UTPP is now estimated to provide a net savings of over $90 million to rate payers as compared to the open market purchases.

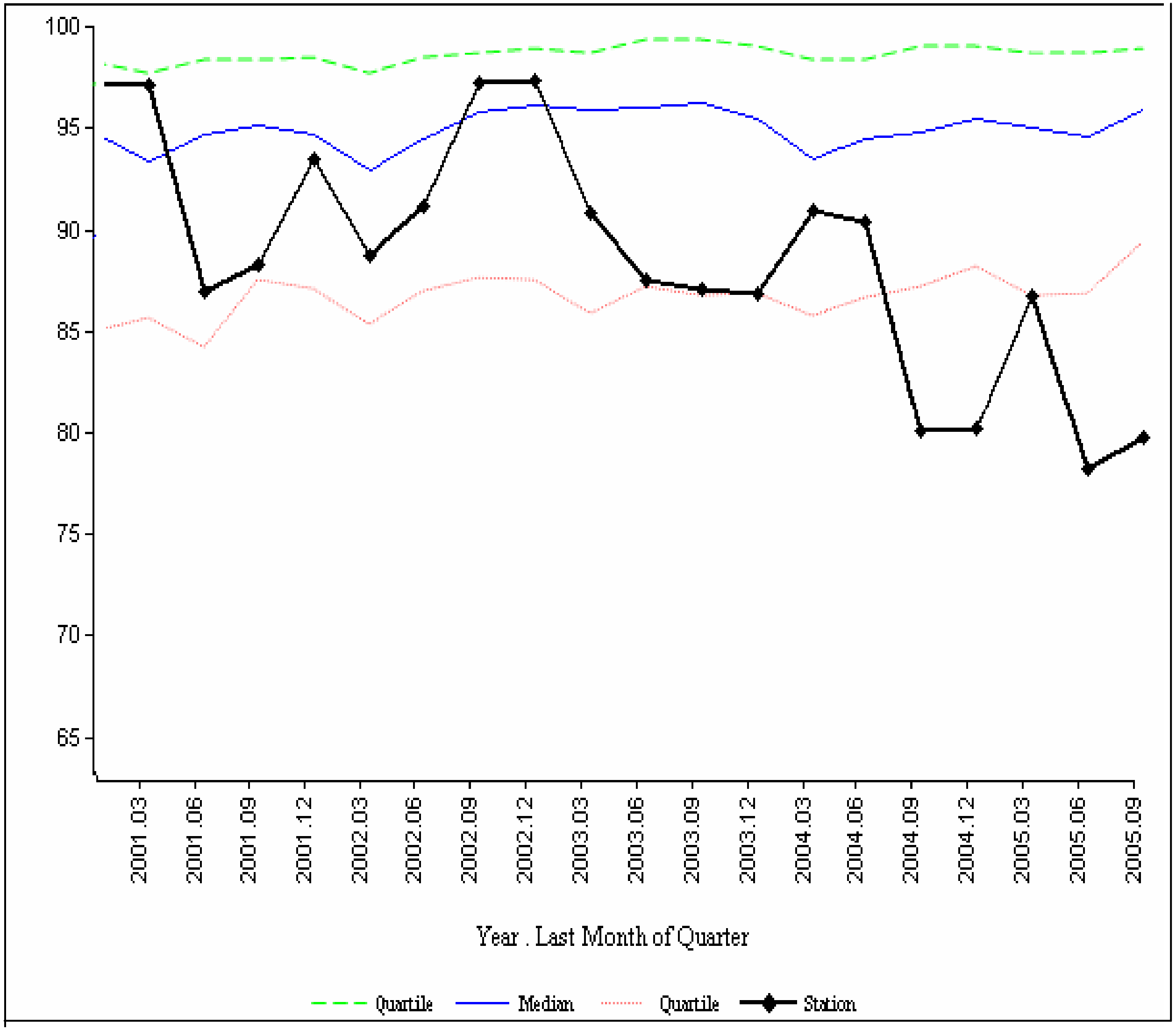
COLUMBIA GENERATING STATION LONG RANGE PLAN

Scott Oxenford
Vice President, Technical Services
ENERGY NORTHWEST

Columbia Generating Station Power History



Columbia Performance Indicator



Capital Projects
($ in Millions)

Fiscal Year	Delta from LRP	Major Projects
2007	$30.3	• Turbine Digital Electro-Hydraulic Control System • Main Transformer • Large Pumps and Motors • Process Radiation Monitoring System • Primary Access Area Search Equipment* • Design Basis Upgrade* • Feed Water Heaters** • Plant Life Extension
2008	$16.1	• Main Condenser (Planning) • Large Pumps and Motors • Plant Life Extension
2009	$19.4	• Main Condenser (Replacement) • Large Pumps and Motors • Plant Life Extension
2010	$14.7	• Large Pumps and Motors • Main Transformer • Supplemental Spent Fuel Pool Cooling (Planning) • Plant Life Extension
Total	$80.5	

O&M Projects
($ in Millions)

Fiscal Year	*Delta from LRP*	*Major Projects*
2007	***$8.2***	• *Chemical Decontamination* • *Main and Auxiliary Jet Pump Wedges*
2008	***$0.2***	• *Reactor Recirculation Pump Mechanical Seal*
2009	***$16.0***	• *Spent Fuel Pool Cleanup* • *Feed Water Drive Turbine Overhaul*
2010	***$2.2***	• *Permanent Lead Shielding for Nozzles*
Total	***$26.6***	

Incremental Outage

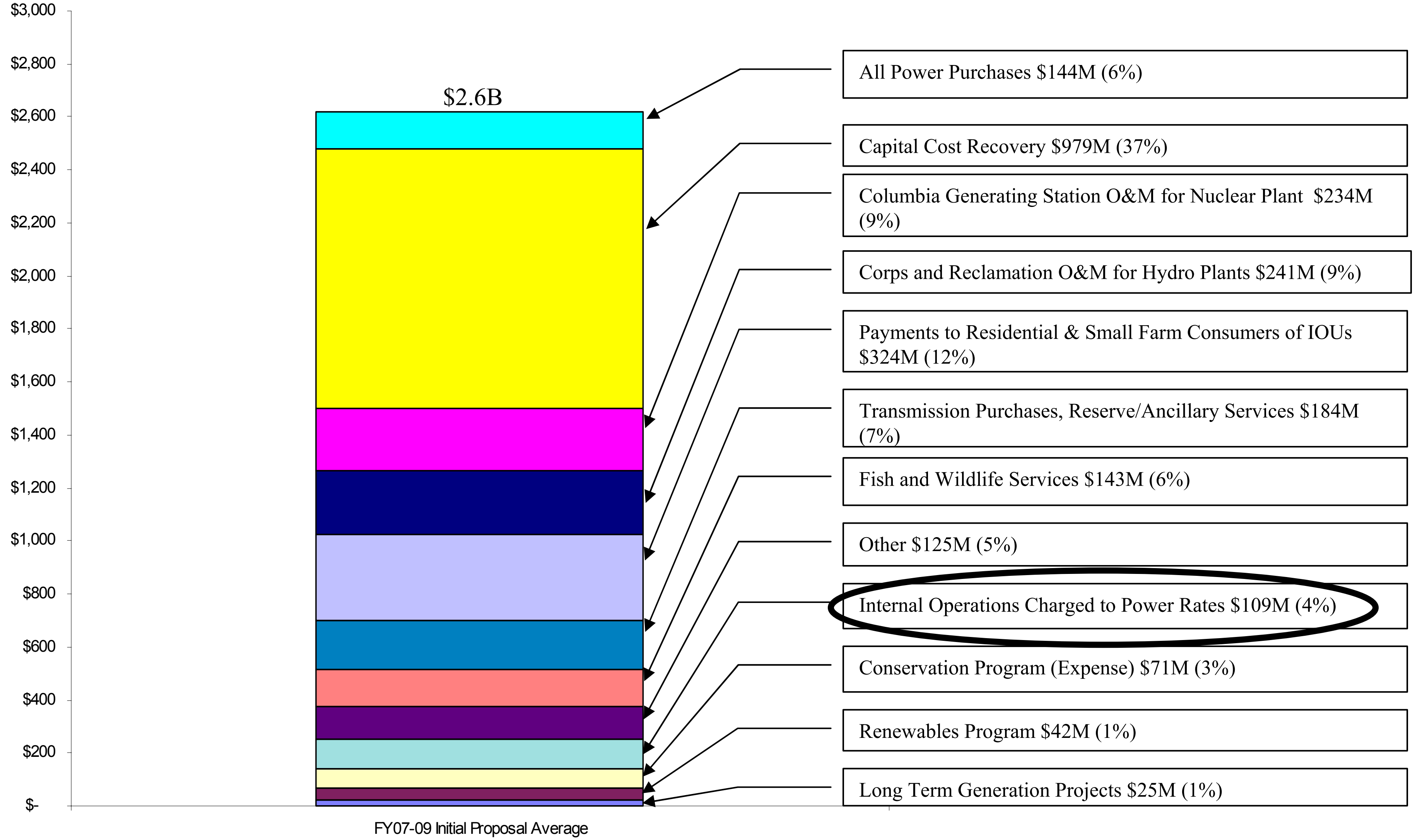
($ in Millions)

Fiscal Year	Delta from LRP	Major Impacts
2007	$7.6	• Support for additional projects
2008	$0.0	• No Outage
2009	$8.1	• Support for additional projects
2010	$0.0	• No Outage
Total	$15.7	

Power Function Review II

Internal Operations Charged to Power (EPIP)

Average Annual Power Expenses for FY07-09



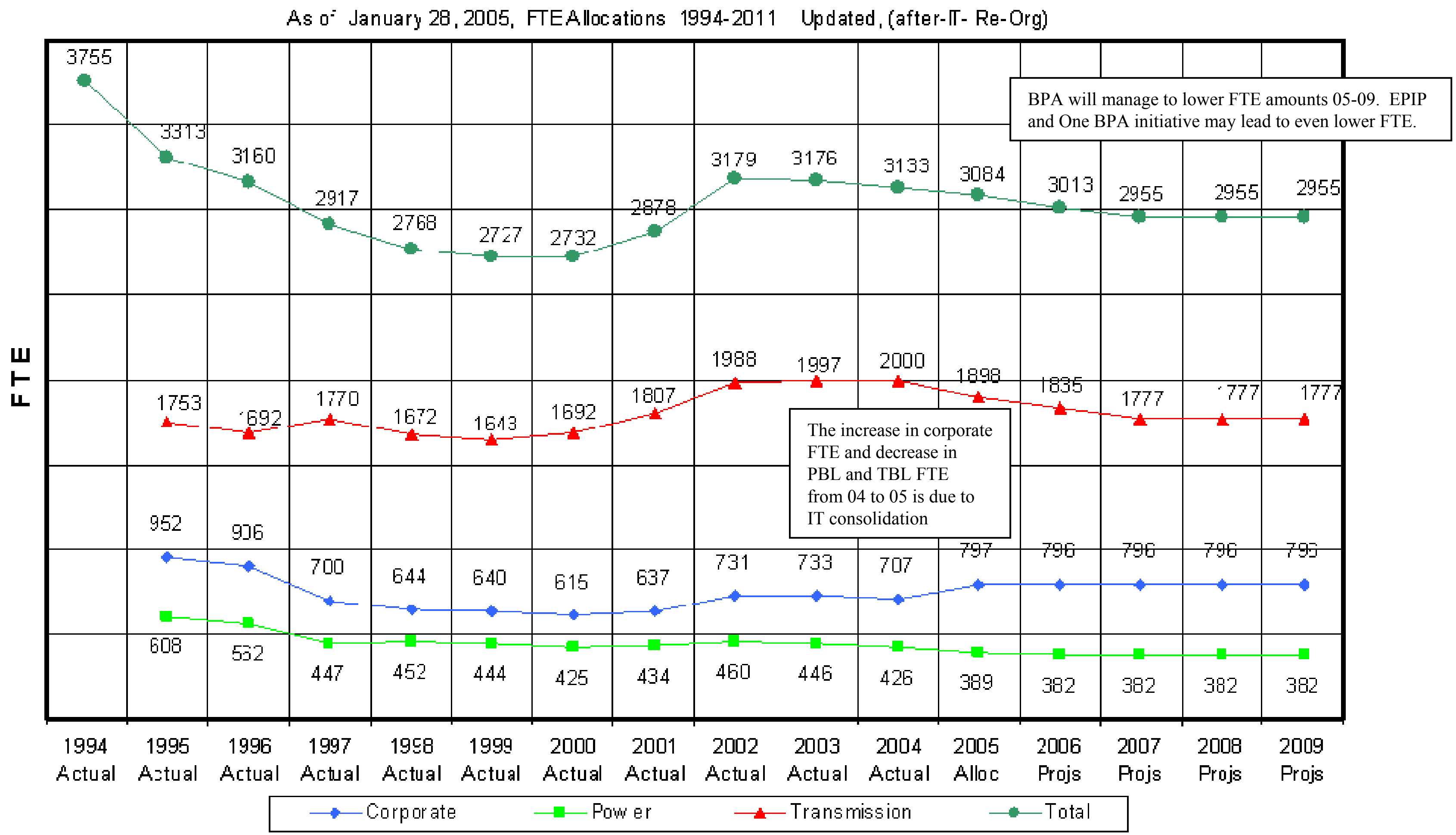
Internal Operations Charged To Power

Potential cost reduction (Scorecard, Line 27):

- BPA has kept its Internal Operations Charged to Power costs at FY 2001 levels during this rate period and is forecast to stay at approximately the same level in the FY07-09 rate period.
- In the PFR I, it was agreed to put an $8M/year reduction in the Initial Proposal forecast to capture savings for the implemented Enterprise Process Improvement Projects (EPIP).

Internal Operations Charged To Power

BPA FTE: 1994 to 2009



Update on BPA's Enterprise Process Improvement Program (EPIP)

What is BPA's Enterprise Process Improvement Program (EPIP)?

- EPIP is a major BPA initiative to achieve one of the Agency's key strategic objectives:
  - Effective cost management through its systems and processes (I1)
- The Program's goal is to help BPA become more efficient and effective by reducing costs and increasing productivity. This will help to lessen rate increases and will deliver higher value to the region and employees
- EPIP was requested by BPA customers

Administrator's Commitment to Customer Collaborative

(9/11/03 Letter from Wright to Adams/ Benedetti)

- Aggressively pursue and implement a Process Improvement Program
- Use outside expertise to define opportunities
- Work with customers in determining scope, contractor selection process and process improvement work plan
- Provide regular updates to customers

Key Drivers for Change

- It is BPA's public service responsibility to deliver services at the lowest rates consistent with sound business principles
- Significant opportunities to lower internal costs and increase productivity exist throughout the Agency.
- To manage upcoming changes in BPA's workforce (e.g., high expected retirement rate in next few years)
- Pro-active change will be easier, less painful and more effective than change imposed by (external) crisis
- To keep pace with an increasingly competitive world
- To meet the President's Management Agenda to reduce government costs and to comply with increased internal controls and accountability
- To increase Agency's credibility by demonstrating that BPA can make difficult internal changes to become more efficient and effective

KEMA identified 23 Areas for Efficiencies

Category 1: Organizational Impacts
1 Performance and Process Management 2 Organizational Design and Governance 3 Strategic Planning 4 Capital Allocation & Asset Management 5 Agency Offerings Portfolio
Category 2: Tactical
6 Information Technology 7 Communications & Regional Relations 8 Transmission: Plan, Design, Build 9 Tansmission Field Operations 10 Business Planning & Budgeting 11 Shared Service Model 12 Rates Strategy 13 Risk Management
Category 3: More Difficult or of Lower Value
14 Energy Efficiency Program Management 15 Fish & Wildlife Program Management 16 Marketing & Sales 17 Audit 18 Human Resources 19 Supply Chain 20 Other Support Services 21 Hydro & Nuclear Operations 22 Finance & Accounting 23 Scheduling, Contracts & Billing/Settlement

EPIP Phase One

- Of the 23 areas identified for efficiency opportunities, 6 key areas were selected for Phase One*:
  - **Information Technology**
  - **Public Affairs and Communications**
  - **Transmission Plan, Design, Build**
  - **Human Resources and Staff Management**
  - **Energy Efficiency**
  - **Marketing and Sales**
- In total, Phase One is targeting $65 - $80 million in annual savings that we expect to realize through process efficiencies over the next 3 – 5 years

*Originally Fish and Wildlife made a 7th initiative but has been put on hold pending completion of its Pisces Contract management project.

Cost Saving Challenges

Enterprise Process Improvement Project – Phase One				
	Baseline Costs (FY 2004 $million) *estimate*	**Baseline Staff** BFTE & CFTE (FY 2004) *estimate*	**Cost Reduction Challenges**	**Targeted Savings** ($millions)
Transmission Plan, Design, Build	291	500	15% or more	30 to 45+
Information Technology	95	500	25% by end of FY2006	24
Marketing and Sales	22	202	15% or more	3+
Human Resources	13	125	40% or more	5+
Public Affairs	8	73	30%	2
Energy Efficiency Contract Management	7	64	15% or more	1+
Totals - Phase One	**436**	**1464**		**65 to 80+** **(18%+ overall average)**

Phase One Achievements to Date

- **Information Technology (IT)**
  - Consolidation and reorganization completed
  - Important initiatives are in "project status" and moving out into operations:
    - FY 2006 expense budget is $5 million (10%) lower than FY 2005; FY 2006 capital budget is $15 million (30%) lower than FY 2005
    - BPA FTE reduced by 28; Contractor FTE reduced by 55. This represents a 16% reduction in the IT workforce
    - Re-competed IT service contracts, consolidating from 23 to 8 providers
    - Agency Prioritization Steering Committee is fully functioning, developing an Agency-wide, business-centric IT project portfolio
  - Achieving cost reduction targets will be complicated by the increased demand for IT support and automation outlined in other EPIP study recommendations

- **Public Affairs**
  - This function was reorganized at the start of FY 2006, consolidating communications, public affairs, and tribal relations staff from across BPA into the Chief Public Affairs Office
    - Staff level reduced by 16% (12 FTE)
    - BPA Today has been rolled out, consolidating numerous other publications

Phase One Achievements to Date - Continued

- **Transmission Plan, Design, Build**
  - Project structure and approach developed – 3 staged approach will be used
  - Phase One Implementation teams have been staffed and launched
  - Eleven teams including
    - Risk Management and Planning (estimated benefits of $15 million/year)
    - Standards Group (estimated benefits of $8.5 million/year)
    - Improved Planning Group (estimated benefits of $2.3 million/year)
    - 8 Others (estimated benefits of $15.1 million/year)
  - Savings in this area would have no impact on power rates

- **Human Resources**
  - Consolidation and reorganization are now in place
  - Staff level reduced by 5% (7 FTE)
  - Detailed implementation planning is in progress

- **Energy Efficiency**
  - Reorganization has been completed
  - A new, automated contract management system is fully implemented

- **Marketing and Sales**
  - Functional review and proposed future state to be completed February 2006

EPIP Phase Two

- Three new Functional reviews are currently underway
  - **Transmission O&M**
  - **Asset Management**
  - **Supply Chain**

- Functional reviews of each area began August 2005 and future state recommendations are expected to be completed January – March 2006

- These are expected to be large cost opportunity areas for BPA

Power Rate Impacts of EPIP Savings – PFR II Update:

- In PFR I, BPA committed to include in the Initial Rate Proposal a forecast of savings from process improvement efforts of $8 million per year (2007-2009). At that time the sources of the savings were not identified.

- Subsequent work on EPIP Phase I studies and early process improvement efforts in the studies functions have confirmed this early estimate, giving us greater confidence that EPIP improvements will yield the
$8 million in savings assumed in PFR 1.

- The preliminary nature of Phase II studies, and their predominately transmission focus, do not warrant a change to this original estimate of power rate savings.

EPIP Project Approach

- Process Improvement Methodology supported by strong Change Management and Project Management structure

- Outside Help
  - KEMA
    - Benchmarking and Industry Expertise
    - Process Improvement and Change Management Expertise
  - Customer Perspective
    - Ken Canon, ICNU
    - Steve Marshall, Snohomish PUD
    - Pat Reiten, PNGC

- Phased Approach

Program Costs to Date

- BPA contracted with KEMA, an international energy consulting firm with specialized industry expertise in benchmarking and process improvement for assistance this project

- Contract cost to date (Nov. 2004 – Dec 2005):
  $4.5 million

EPIP Stages

Project Mobilization	Current State Assessment	Process Analysis	Future State Solution Design	Solution Implementation and Refinement
Change Management				
Kick-Off the Project	***Understand Current Processes***	***Identify Improvement Opportunities***	***Design the Solution***	***Realize the Value***
▪ Set up the PMO and the Project Teams ▪ Determine roles and responsibilities ▪ Conduct training ▪ Conduct kick-off meetings	▪ Identify and prioritize processes ▪ Review documentation responsibilities ▪ Conduct interviews ▪ Document processes and operating model elements	▪ Analyze processes ▪ Compare to best practices ▪ Categorize issues ▪ Prioritize improvement opportunities	▪ Create business cases around alternatives ▪ Design detailed solution ▪ Develop systems and technical design ▪ Design organizational requirements ▪ Identify and implement “Quick Hits”	▪ Construct new processes or systems ▪ Perform testing ▪ Implement solution ▪ Measure progress

Future Planned Phases

- Organization and Governance Structure (One BPA) – FY 06
- Finance EPIP – FY 07

BPA Financial Disclosure Information

- The information on the effect on the revenue requirement is a derived estimate for presentation purposes and may not be found in Agency Financial Information releases but is provided for discussion or exploratory purposes only as *projections of program activity levels, etc.* Such information should be used only for the purpose for which it was provided and should not be recommunicated by the recipient without the foregoing qualification.

- All FY ’06-’09 information was provided in March 2006 and cannot be found in BPA-approved Agency Financial Information but is provided for discussion or exploratory purposes only as projections of program activity levels, etc.

- All FY ’97-’05 information was provided in March 2006 and is consistent with audited actuals that contain BPA-approved Agency Financial Information.